Statement of Basis of the Federal Operating Permit

City Public Service Board

Site Name: Calaveras Lake Plant
Physical Location: 12940 S US Highway 181
Nearest City: San Antonio
County: Bexar

Permit Number: O8
Project Type: Renewal

Standard Industrial Classification (SIC) Code: 4911
SIC Name: Electric Services

This Statement of Basis sets forth the legal and factual basis for the draft permit conditions in accordance with 30 TAC §122.201(a)(4). Per 30 TAC §§ 122.241 and 243, the permit holder has submitted an application under § 122.134 for permit renewal. This document may include the following information:

A description of the facility/area process description;
A basis for applying permit shields;
A list of the federal regulatory applicability determinations;
A table listing the determination of applicable requirements;
A list of the New Source Review Requirements;
The rationale for periodic monitoring methods selected;
The rationale for compliance assurance methods selected;
A compliance status; and
A list of available unit attribute forms.

Prepared on: August 4, 2017

Operating Permit
Basis of Determination

Permit Area Process Description
The Calaveras Lake Plant consists of three co-located facilities: the O. W. Sommers Plant, the J.T. Deely Plant, and the J.K. Spruce Plant. The Calaveras site consists of two natural gas-fired steam electric generating units at Sommers, three coal-fired units at Deely and Spruce, and the associated fuel and material handling facilities. These electric generating units have the combined capacity to generate 2,185 net megawatts of electricity. The two gas units at Sommers are equipped to utilize No. 2 through No. 6 fuel oil. For ignition and flame stabilization, the Deely coal-fired units use fuel oil and the Spruce coal-fired unit uses natural gas. The burning of coal at Deely and Spruce is considered the normal operating condition.

FOPs at Site

The "application area" consists of the emission units and that portion of the site included in the application and this permit. Multiple FOPs may be issued to a site in accordance with 30 TAC § 122.201(e). When there is only one area for the site, then the application information and permit will include all units at the site. Additional FOPs that exist at the site, if any, are listed below.

Additional FOPs: None

Major Source Pollutants

The table below specifies the pollutants for which the site is a major source:

Major Pollutants	VOC, SO_2, PM, NO_X, HAPs, CO

Reading State of Texas's Federal Operating Permit

The Title V Federal Operating Permit (FOP) lists all state and federal air emission regulations and New Source Review (NSR) authorizations (collectively known as "applicable requirements") that apply at a particular site or permit area (in the event a site has multiple FOPs). **The FOP does not authorize new emissions or new construction activities.** The FOP begins with an introductory page which is common to all Title V permits. This page gives the details of the company, states the authority of the issuing agency, requires the company to operate in accordance with this permit and 30 Texas Administrative Code (TAC) Chapter 122, requires adherence with NSR requirements of 30 TAC Chapter 116, and finally indicates the permit number and the issuance date.

This is followed by the table of contents, which is generally composed of the following elements. Not all permits will have all of the elements.

- General Terms and Conditions
- Special Terms and Conditions
    - Emissions Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting
    - Additional Monitoring Requirements
    - New Source Review Authorization Requirements
    - Compliance Requirements
    - Protection of Stratosphere Ozone
    - Permit Location
    - Permit Shield (30 TAC § 122.148)
- Attachments
    - Applicable Requirements Summary
        - Unit Summary
        - Applicable Requirements Summary
    - Additional Monitoring Requirements

    - Permit Shield
    - New Source Review Authorization References
    - Compliance Plan
    - Alternative Requirements
- Appendix A
    - Acronym list
- Appendix B
    - Copies of major NSR authorizations

General Terms and Conditions

The General Terms and Conditions are the same and appear in all permits. The first paragraph lists the specific citations for 30 TAC Chapter 122 requirements that apply to all Title V permit holders. The second paragraph describes the requirements for record retention. The third paragraph provides details for voiding the permit, if applicable. The fourth paragraph states that the permit holder shall comply with the requirements of 30 TAC Chapter 116 by obtaining a New Source Review authorization prior to new construction or modification of emission units located in the area covered by this permit. The fifth paragraph provides details on submission of reports required by the permit.

Special Terms and Conditions

Emissions Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting. The TCEQ has designated certain applicable requirements as site-wide requirements. A site-wide requirement is a requirement that applies uniformly to all the units or activities at the site. Units with only site-wide requirements are addressed on Form OP-REQ1 and are not required to be listed separately on a OP-UA Form or Form OP-SUM. Form OP-SUM must list all units addressed in the application and provide identifying information, applicable OP-UA Forms, and preconstruction authorizations. The various OP-UA Forms provide the characteristics of each unit from which applicable requirements are established. Some exceptions exist as a few units may have both site-wide requirements and unit specific requirements.

Other conditions. The other entries under special terms and conditions are in general terms referring to compliance with the more detailed data listed in the attachments.

Attachments

Applicable Requirements Summary. The first attachment, the Applicable Requirements Summary, has two tables, addressing unit specific requirements. The first table, the Unit Summary, includes a list of units with applicable requirements, the unit type, the applicable regulation, and the requirement driver. The intent of the requirement driver is to inform the reader that a given unit may have several different operating scenarios and the differences between those operating scenarios.

The applicable requirements summary table provides the detailed citations of the rules that apply to the various units. For each unit and operating scenario, there is an added modifier called the “index number,” detailed citations specifying monitoring and testing requirements, recordkeeping requirements, and reporting requirements. The data for this table are based on data supplied by the applicant on the OP-SUM and various OP-UA forms.

Additional Monitoring Requirement. The next attachment includes additional monitoring the applicant must perform to ensure compliance with the applicable standard. Compliance assurance monitoring (CAM) is often required to provide a reasonable assurance of compliance with applicable emission limitations/standards for large emission units that use control devices to achieve compliance with applicant requirements. When necessary, periodic monitoring (PM) requirements are specified for certain parameters (i.e. feed rates, flow rates, temperature, fuel type and consumption, etc.) to determine if a term and condition or emission unit is operating within specified limits to control emissions. These additional monitoring approaches may be required for two reasons. First, the applicable rules do not adequately specify monitoring requirements (exception- Maximum Achievable Control Technology Standards (MACTs) generally have sufficient monitoring), and second, monitoring may be required to fill gaps in the monitoring requirements of certain applicable requirements. In situations where the NSR permit is the applicable requirement requiring extra monitoring for a specific emission unit, the preferred solution is to have the monitoring requirements in the NSR permit updated so that all NSR requirements are consolidated in the NSR permit.

Permit Shield. A permit may or may not have a permit shield, depending on whether an applicant has applied for, and justified the granting of, a permit shield. A permit shield is a special condition included in the permit document stating that compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirement(s) or specified applicable state-only requirement(s).

New Source Review Authorization References. All activities which are related to emissions in the state of Texas must have a NSR authorization prior to beginning construction. This section lists all units in the permit and the NSR authorization that allowed the unit to be constructed or modified. Units that do not have unit specific applicable requirements other than the NSR authorization do not need to be listed in this attachment. While NSR permits are not physically a part of the Title V permit, they are legally incorporated into the Title V permit by reference. Those NSR permits whose emissions exceed certain PSD/NA thresholds must also undergo a Federal review of federally regulated pollutants in addition to review for state regulated pollutants.

Compliance Plan. A permit may have a compliance schedule attachment for listing corrective actions plans for any emission unit that is out of compliance with an applicable requirement.

Alternative Requirements. This attachment will list any alternative monitoring plans or alternative means of compliance for applicable requirements that have been approved by the EPA Administrator and/or the TCEQ Executive Director.

Appendix A

Acronym list. This attachment lists the common acronyms used when discussing the FOPs.

Appendix B

Copies of major NSR authorizations applicable to the units covered by this permit have been included in this Appendix, to ensure that all interested persons can access those authorizations.

Stationary vents subject to 30 TAC Chapter 111, Subchapter A, § 111.111(a)(1)(B) addressed in the Special Terms and Conditions

The site contains stationary vents with a flowrate less than 100,000 actual cubic feet per minute (acfm) and constructed either before or after January 31, 1972 which are limited, over a six-minute average, to 20% opacity as required by 30 TAC § 111.111(a)(1)(B). As a site may have a large number of stationary vents that fall into this category, they are not required to be listed individually in the permit's Applicable Requirement Summary. This is consistent with EPA's White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995, that states that requirements that apply identically to emission units at a site can be treated on a generic basis such as source-wide opacity limits.

Periodic monitoring is specified in Special Term and Condition 3.A.(iv) for stationary vents subject to 30 TAC § 111.111(a)(1)(B) to verify compliance with the 20% opacity limit. These vents are not expected to produce visible emissions during normal operation. The TCEQ evaluated the probability of these sources violating the opacity standards and determined that there is a very low potential that an opacity standard would be exceeded. It was determined that continuous monitoring for these sources is not warranted as there would be very limited environmental benefit in continuously monitoring sources that have a low potential to produce visible emissions. Therefore, the TCEQ set the visible observation monitoring frequency for these sources to once per calendar quarter.

The TCEQ has exempted vents that are not capable of producing visible emissions from periodic monitoring requirements. These vents include sources of colorless VOCs, non-fuming liquids, and other materials that cannot produce emissions that obstruct the transmission of light. Passive ventilation vents, such as plumbing vents, are also included in this category. Since this category of vents are not capable of producing opacity due to the physical or chemical characteristics of the emission source, periodic monitoring is not required as it would not yield any additional data to assure compliance with the 20% opacity standard of 30 TAC § 111.111(a)(1)(B).

In the event that visible emissions are detected, either through the quarterly observation or other credible evidence, such as observations from company personnel, the permit holder shall either report a deviation or perform a Test Method 9 observation to determine the opacity consistent with the 6-minute averaging time specified in 30 TAC § 111.111(a)(1)(B). An additional provision is included to monitor combustion sources more frequently than quarterly if alternate fuels are

burned for periods greater than 24 consecutive hours. This will address possible emissions that may arise when switching fuel types.

Stationary Vents subject to 30 TAC Chapter 111 not addressed in the Special Terms and Conditions

All other stationary vents subject to 30 TAC Chapter 111 not covered in the Special Terms and Conditions are listed in the permit's Applicable Requirement Summary. The basis for the applicability determinations for these vents are listed in the Determination of Applicable Requirements table.

Federal Regulatory Applicability Determinations

The following chart summarizes the applicability of the principal air pollution regulatory programs to the permit area:

Regulatory Program	Applicability (Yes/No)
Prevention of Significant Deterioration (PSD)	Yes
Nonattainment New Source Review (NNSR)	No
Minor NSR	Yes
40 CFR Part 60 - New Source Performance Standards	Yes
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPs)	No
40 CFR Part 63 - NESHAPs for Source Categories	Yes
Title IV (Acid Rain) of the Clean Air Act (CAA)	Yes
Title V (Federal Operating Permits) of the CAA	Yes
Title VI (Stratospheric Ozone Protection) of the CAA	Yes
CSAPR (Cross-State Air Pollution Rule)	Yes

Basis for Applying Permit Shields

An operating permit applicant has the opportunity to specifically request a permit shield to document that specific applicable requirements do not apply to emission units in the permit. A permit shield is a special condition stating that compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirements or specified potentially applicable state-only requirements. A permit shield has been requested in the application for specific emission units. For the permit shield requests that have been approved, the basis of determination for regulations that the owner/operator need not comply with are located in the "Permit Shield" attachment of the permit.

Acid Rain Permit

The permitted area is subject to Federal Clean Air Act Title IV Acid Rain rules for Phase II units, as codified in 40 CFR Parts 72 through 78, because it meets the definition of "affected source." Applicability of affected sources are defined in 40 CFR § 72.6 and include those sources that burn fossil fuel, and generates electricity for sale. Under 40 CFR Part 72, incorporated by reference into 30 TAC Chapter 122, all acid rain permits must contain specific terms and conditions, including monitoring, reporting, recordkeeping and excess emission requirements, established by the U.S. EPA. The Title

IV permitting procedures are described within 30 TAC Chapter 122, Subchapter E. The applicable requirements of the Acid Rain Permit are contained in the Special Terms and Conditions of the FOP. The Acid Rain permit is effective as of the date of the issuance of the FOP and has a term ending in concurrence with the FOP.

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) was established to mitigate the interstate transport of NO_x and SO_2 which contribute to the formation of fine particles (PM 2.5) and ground-level ozone and has replaced the previous Clean Air Interstate Rule (CAIR) program. The EPA has promulgated a model cap and trade program in 40 CFR Part 97 to implement CSAPR. This rule has been adopted by reference into 30 TAC Chapter 122 as part of an effective rulemaking (Rule Project No. 2016-012-122-AI), which included the repeal of 30 TAC Chapter 122, Subchapter E, Division 2: Clean Air Interstate Rule.

The permitted area is subject to CSAPR as it contains units that meet a definition of a CSAPR unit in 40 CFR Part 97 (CSAPR NO_x and SO_2 Trading Programs). The applicable CSAPR requirements are contained in the Special Terms and Conditions of the FOP.

Insignificant Activities

In general, units not meeting the criteria for inclusion on either Form OP-SUM or Form OP-REQ1 are not required to be addressed in the operating permit application. Examples of these types of units include, but are not limited to, the following:

1. Office activities such as photocopying, blueprint copying, and photographic processes.
2. Sanitary sewage collection and treatment facilities other than those used to incinerate wastewater treatment plant sludge. Stacks or vents for sanitary sewer plumbing traps are also included.
3. Food preparation facilities including, but not limited to, restaurants and cafeterias used for preparing food or beverages primarily for consumption on the premises.
4. Outdoor barbecue pits, campfires, and fireplaces.
5. Laundry dryers, extractors, and tumblers processing bedding, clothing, or other fabric items generated primarily at the premises. This does not include emissions from dry cleaning systems using perchloroethylene or petroleum solvents.
6. Facilities storing only dry, sweet natural gas, including natural gas pressure regulator vents.
7. Any air separation or other industrial gas production, storage, or packaging facility. Industrial gases, for purposes of this list, include only oxygen, nitrogen, helium, neon, argon, krypton, and xenon.
8. Storage and handling of sealed portable containers, cylinders, or sealed drums.
9. Vehicle exhaust from maintenance or repair shops.
10. Storage and use of non-VOC products or equipment for maintaining motor vehicles operated at the site (including but not limited to, antifreeze and fuel additives).
11. Air contaminant detectors and recorders, combustion controllers and shut-off devices, product analyzers, laboratory analyzers, continuous emissions monitors, other analyzers and monitors, and emissions associated with sampling activities. Exception to this category includes sampling activities that are deemed fugitive emissions and under a regulatory leak detection and repair program.
12. Bench scale laboratory equipment and laboratory equipment used exclusively for chemical and physical analysis, including but not limited to, assorted vacuum producing devices and laboratory fume hoods.
13. Steam vents, steam leaks, and steam safety relief valves, provided the steam (or boiler feedwater) has not contacted other materials or fluids containing regulated air pollutants other than boiler water treatment chemicals.
14. Storage of water that has not contacted other materials or fluids containing regulated air pollutants other than boiler water treatment chemicals.
15. Well cellars.
16. Fire or emergency response equipment and training, including but not limited to, use of fire control equipment including equipment testing and training, and open burning of materials or fuels associated with firefighting training.
17. Crucible or pot furnaces with a brim full capacity of less than 450 cubic inches of any molten metal.
18. Equipment used exclusively for the melting or application of wax.
19. All closed tumblers used for the cleaning or deburring of metal products without abrasive blasting, and all open tumblers with a batch capacity of 1,000 lbs. or less.

20. Shell core and shell mold manufacturing machines.
21. Sand or investment molds with a capacity of 100 lbs. or less used for the casting of metals;
22. Equipment used for inspection of metal products.
23. Equipment used exclusively for rolling, forging, pressing, drawing, spinning, or extruding either hot or cold metals by some mechanical means.
24. Instrument systems utilizing air, natural gas, nitrogen, oxygen, carbon dioxide, helium, neon, argon, krypton, and xenon.
25. Battery recharging areas.
26. Brazing, soldering, or welding equipment.

Determination of Applicable Requirements

The tables below include the applicability determinations for the emission units, the index number(s) where applicable, and all relevant unit attribute information used to form the basis of the applicability determination. The unit attribute information is a description of the physical properties of an emission unit which is used to determine the requirements to which the permit holder must comply. For more information about the descriptions of the unit attributes specific Unit Attribute Forms may be viewed at www.tceq.texas.gov/permitting/air/nav/air_all_ua_forms.html.

A list of unit attribute forms is included at the end of this document. Some examples of unit attributes include construction date; product stored in a tank; boiler fuel type; etc.. Generally, multiple attributes are needed to determine the requirements for a given emission unit and index number. The table below lists these attributes in the column entitled "Basis of Determination." Attributes that demonstrate that an applicable requirement applies will be the factual basis for the specific citations in an applicable requirement that apply to a unit for that index number. The TCEQ Air Permits Division has developed flowcharts for determining applicability of state and federal regulations based on the unit attribute information in a Decision Support System (DSS). These flowcharts can be accessed via the internet at www.tceq.texas.gov/permitting/air/nav/air_supportsys.html. The Air Permits Division staff may also be contacted for assistance at (512) 239-1250.

The attributes for each unit and corresponding index number provide the basis for determining the specific legal citations in an applicable requirement that apply, including emission limitations or standards, monitoring, recordkeeping, and reporting. The rules were found to apply or not apply by using the unit attributes as answers to decision questions found in the flowcharts of the DSS. Some additional attributes indicate which legal citations of a rule apply. The legal citations that apply to each emission unit may be found in the Applicable Requirements Summary table of the draft permit. There may be some entries or rows of units and rules not found in the permit, or if the permit contains a permit shield, repeated in the permit shield area. These are sets of attributes that describe negative applicability, or; in other words, the reason why a potentially applicable requirement does not apply.

If applicability determinations have been made which differ from the available flowcharts, an explanation of the decisions involved in the applicability determination is specified in the column "Changes and Exceptions to RRT." If there were no exceptions to the DSS, then this column has been removed.

The draft permit includes all emission limitations or standards, monitoring, recordkeeping and reporting required by each applicable requirement. If an applicable requirement does not require monitoring, recordkeeping, or reporting, the word "None" will appear in the Applicable Requirements Summary table. If additional periodic monitoring is required for an applicable requirement, it will be explained in detail in the portion of this document entitled "Rationale for Compliance Assurance Monitoring (CAM)/ Periodic Monitoring Methods Selected."

When attributes demonstrate that a unit is not subject to an applicable requirement, the applicant may request a permit shield for those items. The portion of this document entitled "Basis for Applying Permit Shields" specifies which units, if any, have a permit shield.

Operational Flexibility

When an emission unit has multiple operating scenarios, it will have a different index number associated with each operating condition. This means that units are permitted to operate under multiple operating conditions. The applicable requirements for each operating condition are determined by a unique set of unit attributes. For example, a tank may store two different products at different points in time. The tank may, therefore, need to comply with two distinct sets of

requirements, depending on the product that is stored. Both sets of requirements are included in the permit, so that the permit holder may store either product in the tank.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
EMGEN-1	40 CFR Part 60, Subpart IIII	60IIII-1	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification after 07/11/2005. Diesel = Diesel fuel is used. Kilowatts = Power rating is greater than 560 KW and less than or equal to 2237 KW. Exemptions = The CI ICE is not exempt due to national security, testing at an engine test cell/stand or as a temporary replacement. Displacement = Displacement is less than 10 liters per cylinder. Service = CI ICE is an emergency engine. Standards = The emergency CI ICE does not meet the standards applicable to non-emergency engines. Commencing = CI ICE was newly constructed after 07/11/2005. Compliance Option = The CI ICE and control device is installed, configured, operated, and maintained according to the manufacturer's emission-related written instructions. Manufacture Date = Date of manufacture was after 04/01/2006. Model Year = CI ICE was manufactured in model year 2007.	
EMGEN-1	40 CFR Part 63, Subpart ZZZZ	63ZZZZ	HAP Source = Any stationary source or group of stationary sources of hazardous air pollutants meeting the definition of a major source as described in 40 CFR § 63.2. Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction on or after June 12, 2006. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii).	
EMGEN-2	40 CFR Part 60, Subpart IIII	60IIII-1	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification after 07/11/2005. Diesel = Diesel fuel is used. Kilowatts = Power rating greater than or equal to 368 KW and less than or equal to 560KW. Exemptions = The CI ICE is not exempt due to national security, testing at an engine test cell/stand or as a temporary replacement. Displacement = Displacement is less than 10 liters per cylinder. Service = CI ICE is an emergency engine. Standards = The emergency CI ICE does not meet the standards applicable to non-emergency engines. Commencing = CI ICE was newly constructed after 07/11/2005. Compliance Option = The CI ICE and control device is installed, configured, operated, and maintained according to the manufacturer's emission-related written instructions. Manufacture Date = Date of manufacture was after 04/01/2006. Model Year = CI ICE was manufactured in model year 2007.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
EMGEN-2	40 CFR Part 63, Subpart ZZZZ	63ZZZZ	HAP Source = Any stationary source or group of stationary sources of hazardous air pollutants meeting the definition of a major source as described in 40 CFR § 63.2. Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction on or after June 12, 2006. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii).	
EMGEN-DAM	40 CFR Part 60, Subpart IIII	60IIII-1	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
EMGEN-DAM	40 CFR Part 63, Subpart ZZZZ	63ZZZZ	HAP Source = Any stationary source or group of stationary sources of hazardous air pollutants meeting the definition of a major source as described in 40 CFR § 63.2. Brake HP = Stationary RICE with a brake HP greater than or equal to 300 HP and less than or equal to 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
EMGEN-GATE	40 CFR Part 60, Subpart IIII	60IIII-1	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification after 07/11/2005. Diesel = Diesel fuel is used. Kilowatts = Power rating greater than or equal to 130 KW and less than or equal to 368 KW. Exemptions = The CI ICE is not exempt due to national security, testing at an engine test cell/stand or as a temporary replacement. Displacement = Displacement is less than 10 liters per cylinder. Service = CI ICE is an emergency engine. Standards = The emergency CI ICE does not meet the standards applicable to non-emergency engines. Commencing = CI ICE was newly constructed after 07/11/2005. Compliance Option = The CI ICE and control device is installed, configured, operated, and maintained according to the manufacturer's emission-related written instructions. Manufacture Date = Date of manufacture was after 04/01/2006. Model Year = CI ICE was manufactured in model year 2010.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
EMGEN-GATE	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-1	HAP Source = Any stationary source or group of stationary sources of hazardous air pollutants meeting the definition of a major source as described in 40 CFR § 63.2. Brake HP = Stationary RICE with a brake HP greater than or equal to 250 HP and less than 300 HP. Construction/Reconstruction Date = Commenced construction or reconstruction on or after June 12, 2006. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii).	
PUMPFW-JKS	40 CFR Part 60, Subpart IIII	60IIII-1	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
PUMPFW-JKS	40 CFR Part 63, Subpart ZZZZ	63ZZZZ	HAP Source = Any stationary source or group of stationary sources of hazardous air pollutants meeting the definition of a major source as described in 40 CFR § 63.2. Brake HP = Stationary RICE with a brake HP greater than or equal to 300 HP and less than or equal to 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
PUMPFW-JTD	40 CFR Part 60, Subpart IIII	60IIII-1	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
PUMPFW-JTD	40 CFR Part 63, Subpart ZZZZ	63ZZZZ	HAP Source = Any stationary source or group of stationary sources of hazardous air pollutants meeting the definition of a major source as described in 40 CFR § 63.2. Brake HP = Stationary RICE with a brake HP greater than or equal to 300 HP and less than or equal to 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
PUMPFW-OWS	40 CFR Part 60, Subpart IIII	60IIII-1	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
PUMPFW-OWS	40 CFR Part 63, Subpart ZZZZ	63ZZZZ	HAP Source = Any stationary source or group of stationary sources of hazardous air pollutants meeting the definition of a major source as described in 40 CFR § 63.2. Brake HP = Stationary RICE with a brake HP greater than or equal to 300 HP and less than or equal to 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
ETH-UST	30 TAC Chapter 115, Storage of VOCs	R115-1	Construction Date = Date not determined since 30 TAC § 115.117(c)(3) exemption is not utilized Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Tank Description = Tank using a submerged fill pipe True Vapor Pressure = True vapor pressure is greater than or equal to 1.5 psia Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons	
G-1A	30 TAC Chapter 115, Storage of VOCs	R-5112-1	Construction Date = On or after May 12, 1973 Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Tank Description = Tank using a submerged fill pipe True Vapor Pressure = True vapor pressure is greater than or equal to 1.5 psia Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons	
ETH-UNLDG	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas, crude oil, condensate and gasoline. Transfer Type = Only unloading. True Vapor Pressure = True vapor pressure is greater than or equal to 1.5 psia. Daily Throughput = Loading less than 20,000 gallons per day. Control Options = Vapor balance system.	-- Affected Pollutant - VOC: Monitoring/Testing – § 115.214(b)(1)(D) and § 115.214(b)(1)(D)(i) added to specify applicability of inspection requirements

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
FUELOILLDG	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas, crude oil, condensate and gasoline. Transfer Type = Only loading. True Vapor Pressure = True vapor pressure is less than 1.5 psia.	-- Affected Pollutant - VOC: Monitoring/Testing – § 115.214(b)(1)(D) and § 115.214(b)(1)(D)(i) added to specify applicability of inspection requirements
FUELOILUNL	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas, crude oil, condensate and gasoline. Transfer Type = Only unloading. True Vapor Pressure = True vapor pressure is less than 1.5 psia.	-- Affected Pollutant - VOC: Monitoring/Testing – § 115.214(b)(1)(D) and § 115.214(b)(1)(D)(i) added to specify applicability of inspection requirements
NAPH-UNLDG	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas, crude oil, condensate and gasoline. Transfer Type = Only unloading. True Vapor Pressure = True vapor pressure is less than 1.5 psia.	-- Affected Pollutant - VOC: Monitoring/Testing – § 115.214(b)(1)(D) and § 115.214(b)(1)(D)(i) added to specify applicability of inspection requirements
USEDOILLDG	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas, crude oil, condensate and gasoline. Transfer Type = Only loading. True Vapor Pressure = True vapor pressure is less than 1.5 psia.	-- Affected Pollutant - VOC: Monitoring/Testing – § 115.214(b)(1)(D) and § 115.214(b)(1)(D)(i) added to specify applicability of inspection requirements
WKFLUIDUNL	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas, crude oil, condensate and gasoline. Transfer Type = Only unloading. True Vapor Pressure = True vapor pressure is less than 1.5 psia.	-- Affected Pollutant - VOC: Monitoring/Testing – § 115.214(b)(1)(D) and § 115.214(b)(1)(D)(i) added to specify applicability of inspection requirements

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
WTCHEM UNLG	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas, crude oil, condensate and gasoline. Transfer Type = Only unloading. True Vapor Pressure = True vapor pressure is less than 1.5 psia.	-- Affected Pollutant - VOC: Monitoring/Testing – § 115.214(b)(1)(D) and § 115.214(b)(1)(D)(i) added to specify applicability of inspection requirements
BOILER 1 JTD1	30 TAC Chapter 111, Nonagricultural Processes	R1153	Source Type = Solid fossil fuel-fired steam generator.	
BOILER 1 JTD1	30 TAC Chapter 112, Sulfur Compounds	R-112-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment.	
BOILER 1 JTD1	30 TAC Chapter 117, Subchapter E, Division 1	R73020-1	Date Placed in Service = Before December 31, 1995. NOx Emission Limitation = Unit is complying with the System Cap under 30 TAC § 117.3020. Unit Exempt = The unit does not qualify for any exemptions under the rule. Location = The unit is not a gas-fired steam generator located in Palo Pinto County as specified in 30 TAC § 117.3005(a). NOx Monitoring = A continuous emissions monitoring system is used to monitor NO_x emissions. Maximum Emission Rate = The owner or operator is using one of the other allowed methods under § 117.3020(e)(1) - (3) to provide substitute emissions compliance when the NO_x monitor is off-line. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	-- Affected Pollutant - NO_X: Monitoring/Testing – § 117.3035(a), § 117.3035(a)(1), § 117.3035(a)(3), § 117.3035(b), § 117.3035(c), § 117.3035(d), and § 117.3040(k) were added to specify initial compliance testing requirements. Monitoring/Testing – [G]§ 117.3040(d)(2) was removed since the permit holder has elected to comply only with the alternative requirements of [G]§ 117.3040(d)(3) for units that are included in a system cap under §117.3020.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 1 JTD1	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Solid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	-- Affected Pollutant - SO2: Monitoring/Testing – § 60.45(c)(3)(i) was removed since the permit holder has elected to comply only with the alternative requirements of § 60.45(c)(3)(ii) for SO2 CEMS span value determination based on criteria in 40 CFR Part 75.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 1 JTD1	40 CFR Part 60, Subpart D	60D-2	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Gaseous fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 1 JTD1	40 CFR Part 60, Subpart D	60D-3	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Gaseous fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Solid fossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	-- Affected Pollutant - SO2: Monitoring/Testing – § 60.45(c)(3)(i) was removed since the permit holder has elected to comply only with the alternative requirements of § 60.45(c)(3)(ii) for SO2 CEMS span value determination based on criteria in 40 CFR Part 75.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 1 JTD1	40 CFR Part 60, Subpart D	60D-4	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Solid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Nonfossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
BOILER 1 JTD1	40 CFR Part 63, Subpart UUUUU	63UUUUU-1	Unit Type = Unit is a coal-fired electric utility steam generating unit as defined in 40 CFR § 63.10042.	
BOILER 2 JTD2	30 TAC Chapter 111, Nonagricultural Processes	R1153	Source Type = Solid fossil fuel-fired steam generator.	
BOILER 2 JTD2	30 TAC Chapter 112, Sulfur Compounds	R-112-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 2 JTD2	30 TAC Chapter 117, Subchapter E, Division 1	R73020-1	Date Placed in Service = Before December 31, 1995. NOx Emission Limitation = Unit is complying with the System Cap under 30 TAC § 117.3020. Unit Exempt = The unit does not qualify for any exemptions under the rule. Location = The unit is not a gas-fired steam generator located in Palo Pinto County as specified in 30 TAC § 117.3005(a). NOx Monitoring = A continuous emissions monitoring system is used to monitor NO_x emissions. Maximum Emission Rate = The owner or operator is using one of the other allowed methods under § 117.3020(e)(1) - (3) to provide substitute emissions compliance when the NO_x monitor is off-line. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	-- Affected Pollutant - NO_X: Monitoring/Testing – § 117.3035(a), § 117.3035(a)(1), § 117.3035(a)(3), § 117.3035(b), § 117.3035(c), and § 117.3035(d), were added to specify initial compliance testing requirements. Monitoring/Testing – [G]§ 117.3040(d)(2) was removed since the permit holder has elected to comply only with the alternative requirements of [G]§ 117.3040(d)(3) for units that are included in a system cap under §117.3020.
BOILER 2 JTD2	30 TAC Chapter 117, Subchapter E, Division 1	R73020-2	Date Placed in Service = Before December 31, 1995. NOx Emission Limitation = Unit is complying with the System Cap under 30 TAC § 117.3020. Unit Exempt = The unit does not qualify for any exemptions under the rule. Location = The unit is not a gas-fired steam generator located in Palo Pinto County as specified in 30 TAC § 117.3005(a). NOx Monitoring = A continuous emissions monitoring system is used to monitor NO_x emissions. Maximum Emission Rate = The owner or operator is using one of the other allowed methods under § 117.3020(e)(1) - (3) to provide substitute emissions compliance when the NO_x monitor is off-line. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.3010(2). Ammonia Monitoring = A continuous emissions monitoring system is used to monitor ammonia emissions.	-- Affected Pollutant - NO_X: Monitoring/Testing – § 117.3035(a), § 117.3035(a)(1), § 117.3035(a)(3), § 117.3035(b), § 117.3035(c), and § 117.3035(d), were added to specify initial compliance testing requirements. Monitoring/Testing – [G]§ 117.3040(d)(2) was removed since the permit holder has elected to comply only with the alternative requirements of [G]§ 117.3040(d)(3) for units that are included in a system cap under §117.3020. -- Affected Pollutant - NH_3: Monitoring/Testing [G]§ 117.3040(d)(3) was added and [G]§ 117.3040(d)(2) was removed since the permit holder has elected to comply only with the alternative requirements of [G]§ 117.3040(d)(3) for units that are included in a system cap under §117.3020.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 2 JTD2	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Solid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	-- Affected Pollutant - SO_2: Monitoring/Testing – § 60.45(c)(3)(i) was removed since the permit holder has elected to comply only with the alternative requirements of § 60.45(c)(3)(ii) for SO_2 CEMS span value determination based on criteria in 40 CFR Part 75.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 2 JTD2	40 CFR Part 60, Subpart D	60D-2	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Gaseous fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 2 JTD2	40 CFR Part 60, Subpart D	60D-3	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Gaseous fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Solid fossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	-- Affected Pollutant - SO_2: Monitoring/Testing – § 60.45(c)(3)(i) was removed since the permit holder has elected to comply only with the alternative requirements of § 60.45(c)(3)(ii) for SO_2 CEMS span value determination based on criteria in 40 CFR Part 75.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
BOILER 2 JTD2	40 CFR Part 60, Subpart D	60D-4	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Solid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Nonfossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
BOILER 2 JTD2	40 CFR Part 63, Subpart UUUUU	63UUUUU-1	Unit Type = Unit is a coal-fired electric utility steam generating unit as defined in 40 CFR § 63.10042.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
GRP-AUXB	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = After June 9, 1989 but on or before February 28, 2005. PM Monitoring Type = No particulate monitoring. Maximum Design Heat Input Capacity = Maximum design heat input capacity is greater than or equal to 10 MMBtu/hr (2.9 MW) but less than or equal to 100 MMBtu (29 MW). SO2 Inlet Monitoring Type = No SO_2 monitoring. Other Subparts = The facility is not covered under 40 CFR Part 60, Subparts AAAA or KKKK, or under an approved State or Federal section 111(d)/129 plan implementing 40 CFR Part 60, Subpart BBBB. SO2 Outlet Monitoring Type = No SO_2 monitoring. Heat Input Capacity = Heat input capacity is greater than or equal to 30 MMBtu/hr (8.7 MW) but less than or equal to 75 MMBtu/hr (22 MW). Technology Type = None. D-Series Fuel Type = Natural gas. ACF Option - SO2 = Other ACF or no ACF. ACF Option - PM = Other ACF or no ACF. 30% Coal Duct Burner = The facility does not combust coal in a duct burner as part of a combined cycle system; or more than 30% of the heat is from combustion of coal and less than 70% is from exhaust gases entering the duct burner.	
GRP-AUXB	40 CFR Part 63, Subpart DDDDD	63DDDDD-1	Construction/Reconstruction Date = Construction or reconstruction began on or before June 4, 2010.	
GRP-OWSSTM	30 TAC Chapter 111, Nonagricultural Processes	R1153	Source Type = Oil or gas fuel-fired steam generator with a heat input greater than 2,500 million Btu per hour.	
GRP-OWSSTM	30 TAC Chapter 112, Sulfur Compounds	R-112-1	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
GRP-OWSSTM	30 TAC Chapter 117, Subchapter E, Division 1	R73020-1	Date Placed in Service = Before December 31, 1995. NOx Emission Limitation = Unit is complying with the System Cap under 30 TAC § 117.3020. Unit Exempt = The unit does not qualify for any exemptions under the rule. Location = The unit is not a gas-fired steam generator located in Palo Pinto County as specified in 30 TAC § 117.3005(a). NOx Monitoring = A continuous emissions monitoring system is used to monitor NO_x emissions. Maximum Emission Rate = The owner or operator is using one of the other allowed methods under § 117.3020(e)(1) - (3) to provide substitute emissions compliance when the NO_x monitor is off-line. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	-- Affected Pollutant - NO_X: Monitoring/Testing – § 117.3035(a), § 117.3035(a)(1), § 117.3035(a)(3), § 117.3035(b), § 117.3035(c), and § 117.3035(d), were added to specify initial compliance testing requirements. Monitoring/Testing – [G]§ 117.3040(d)(2) and [G]§ 117.3040(d)(3) were removed since the units are monitored individually; these requirements only apply if a CEMS is shared among units.
GRP-OWSSTM	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = On or before August 17, 1971.	
P-5 JKS1	30 TAC Chapter 111, Nonagricultural Processes	R1153	Source Type = Solid fossil fuel-fired steam generator.	
P-5 JKS1	30 TAC Chapter 112, Sulfur Compounds	R-112-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit equipped with SO_2 control equipment. FCAA § 412(c) = The unit is subject to the Federal Clean Air Act § 412(c) [FCAA § 412(c)] as amended in 1990.	
P-5 JKS1	30 TAC Chapter 117, Subchapter E, Division 1	R73020-1	Date Placed in Service = Before December 31, 1995. NOx Emission Limitation = Unit is complying with the System Cap under 30 TAC § 117.3020. Unit Exempt = The unit does not qualify for any exemptions under the rule. Location = The unit is not a gas-fired steam generator located in Palo Pinto County as specified in 30 TAC § 117.3005(a). NOx Monitoring = A continuous emissions monitoring system is used to monitor NO_x emissions. Maximum Emission Rate = The owner or operator is using one of the other allowed methods under § 117.3020(e)(1) - (3) to provide substitute emissions compliance when the NO_x monitor is off-line. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	-- Affected Pollutant - NO_X: Monitoring/Testing – § 117.3035(a), § 117.3035(a)(1), § 117.3035(a)(3), § 117.3035(b), § 117.3035(c), and § 117.3035(d) and § 117.3040(k), were added to specify initial compliance testing requirements. Monitoring/Testing – [G]§ 117.3040(d)(2) and [G]§ 117.3040(d)(3) were removed since the units are monitored individually; these requirements only apply if a CEMS is shared among units.
P-5 JKS1	40 CFR Part 60, Subpart D	60Da-1	Construction/Modification Date = After September 18, 1978. Covered Under Subpart Da = The steam generating unit is covered under 40 CFR Part 60, Subpart Da.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
P-5 JKS1	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Solid fossil fuel. Duct Burner = The unit is not a duct burner. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75 [§ 60.49Da(b)(4)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
P-5 JKS1	40 CFR Part 60, Subpart Da	60Da-2	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Natural gas. Duct Burner = The unit is not a duct burner. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75 [§ 60.49Da(b)(4)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
P-5 JKS1	40 CFR Part 60, Subpart Da	60Da-3	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Natural gas. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. D-Series Fuel Type #2 = Solid fossil fuel. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75 [§ 60.49Da(b)(4)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
P-5 JKS1	40 CFR Part 60, Subpart Da	60Da-4	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Solid fossil fuel. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. D-Series Fuel Type #2 = Solid nonfossil fuel. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75 [§ 60.49Da(b)(4)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	
P-5 JKS1	40 CFR Part 63, Subpart UUUUU	63UUUUU-1	Unit Type = Unit is a coal-fired electric utility steam generating unit as defined in 40 CFR § 63.10042.	
P-6	30 TAC Chapter 111, Nonagricultural Processes	R1153	Source Type = Solid fossil fuel-fired steam generator.	
P-6	30 TAC Chapter 112, Sulfur Compounds	R2009	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit equipped with SO_2 control equipment. FCAA § 412(c) = The unit is subject to the Federal Clean Air Act § 412(c) [FCAA § 412(c)] as amended in 1990.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
P-6	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = Constructed after February 28, 2005. Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Solid fossil fuel. Duct Burner = The unit is not a duct burner. PM Monitoring Type = An electrostatic precipitator or a baghouse is used for PM control and PM monitored using COMS per § 60.48Da(o)(2). Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Flow Monitoring System = Continuous flow monitoring system certified according to the requirements of 40 CFR § 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR § 75.21, and validated according to 40 CFR § 75.23. SO2 Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75 [§ 60.49Da(b)(4)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Flow Monitoring System = Continuous flow monitoring system certified according to the requirements of 40 CFR § 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR § 75.21, and validated according to 40 CFR § 75.23. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. % Coal Refuse = The facility burns less than 75% coal refuse on a 12-month rolling average basis. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. FGD = The facility has a flue gas desulfurization system. PM Standard = Input based § 60.42Da(c)(2). SO2 Standard Basis = The facility meets a standard that is output-based. NOX Standard Basis = The facility meets a standard that is output-based.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
P-6	40 CFR Part 60, Subpart Da	60Da-2	Construction/Modification Date = Constructed after February 28, 2005. Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Natural gas. Duct Burner = The unit is not a duct burner. PM Monitoring Type = An electrostatic precipitator or a baghouse is used for PM control and PM monitored using COMS per § 60.48Da(o)(2). Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Flow Monitoring System = Continuous flow monitoring system certified according to the requirements of 40 CFR § 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR § 75.21, and validated according to 40 CFR § 75.23. SO2 Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75 [§ 60.49Da(b)(4)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Flow Monitoring System = Continuous flow monitoring system certified according to the requirements of 40 CFR § 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR § 75.21, and validated according to 40 CFR § 75.23. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. % Coal Refuse = The facility burns less than 75% coal refuse on a 12-month rolling average basis. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. FGD = The facility has a flue gas desulfurization system. PM Standard = Input based § 60.42Da(c)(2). SO2 Standard Basis = The facility meets a standard that is output-based. NOX Standard Basis = The facility meets a standard that is output-based.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
P-6	40 CFR Part 60, Subpart Da	60Da-3	Construction/Modification Date = Constructed after February 28, 2005. Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Natural gas. Duct Burner = The unit is not a duct burner. PM Monitoring Type = An electrostatic precipitator or a baghouse is used for PM control and PM monitored using COMS per § 60.48Da(o)(2). D-Series Fuel Type #2 = Solid fossil fuel. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Flow Monitoring System = Continuous flow monitoring system certified according to the requirements of 40 CFR § 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR § 75.21, and validated according to 40 CFR § 75.23. SO2 Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75 [§ 60.49Da(b)(4)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Flow Monitoring System = Continuous flow monitoring system certified according to the requirements of 40 CFR § 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR § 75.21, and validated according to 40 CFR § 75.23. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. % Coal Refuse = The facility burns less than 75% coal refuse on a 12-month rolling average basis. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. FGD = The facility has a flue gas desulfurization system. PM Standard = Input based § 60.42Da(c)(2). SO2 Standard Basis = The facility meets a standard that is output-based. NOX Standard Basis = The facility meets a standard that is output-based.	
P-6	40 CFR Part 63, Subpart UUUUU	63UUUUU-1	Unit Type = Unit is a coal-fired electric utility steam generating unit as defined in 40 CFR § 63.10042.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
GRP-COAL1	40 CFR Part 60, Subpart Y	60Y-1	Coal Preparation Plant = Coal preparation plant contains thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems or coal transfer and loading systems. Design Capacity = Design capacity is greater than 200 tons of coal per day. Federally Enforceable Limit Option = The plant chooses not to operate under a federally enforceable limit of less than 200 tons per day. Affected Facility = Coal processing and conveying equipment (including breakers and crushers), coal storage Construction/Reconstruction/Modification Date = After October 24, 1974 and before April 28, 2008.	-- Affected Pollutant - PM (OPACITY): Reporting – § 60.258(c) was added to specify reporting requirements related to initial performance testing of § 60.257(a).
GRP-COAL2	40 CFR Part 60, Subpart Y	60Y-1	Coal Preparation Plant = Coal preparation plant contains thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems or coal transfer and loading systems. Design Capacity = Design capacity is greater than 200 tons of coal per day. Federally Enforceable Limit Option = The plant chooses not to operate under a federally enforceable limit of less than 200 tons per day. Affected Facility = Coal processing and conveying equipment (including breakers and crushers), coal storage Construction/Reconstruction/Modification Date = After October 24, 1974 and before April 28, 2008.	-- Affected Pollutant - PM (Opacity): Monitoring/Testing – [G]§ 60.257(a)(2) was added to specify additional requirements for determining opacity for fugitive emission sources. Reporting – § 60.258(c) was added to specify reporting requirements related to initial performance testing of § 60.257(a).
GRP-LIME2	40 CFR Part 60, Subpart OOO	60OOO-1	Plant Type = Crushed stone plant. Portable or Fixed Plant = Fixed. Plant Capacity = Capacity is greater than 25 tons/hr. Capture System = The affected facility is using a capture system for emissions control. Underground Mines = The facility is not located in an underground mine. Control Device Type = Baghouse controlling emissions from only an individual enclosed storage bin. Subpart Applicability = The facility is not subject to 40 CFR Part 60, Subparts F or I, nor does the facility follow, in the plant process, another facility subject to Subparts F or I. Facility Type = Individual storage bin. Construction/Modification Date = After August 31, 1983. Emissions Interference Type = No emissions interference occurs for the affected facility. Replacement Type = Is not replacing an existing facility.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
LFUG-CRSH	40 CFR Part 60, Subpart OOO	60OOO-1	Plant Type = Crushed stone plant. Portable or Fixed Plant = Fixed. Plant Capacity = Capacity is greater than 25 tons/hr. Vent = The building does not contain a vent as defined in 40 CFR § 60.671. Capture System = The affected facility is not using a capture system for emissions control. Underground Mines = The facility is not located in an underground mine. Control Device Type = Control device other than a baghouse controlling emissions from only an individual enclosed storage bin or wet scrubber, or no emissions control. Subpart Applicability = The facility is not subject to 40 CFR Part 60, Subparts F or I, nor does the facility follow, in the plant process, another facility subject to Subparts F or I. Facility Type = Building enclosing one or more affected facilities and complying with the requirements of 40 CFR § 60.672(e). Construction/Modification Date = After August 31, 1983. Replacement Type = Is not replacing an existing facility.	
E-3	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
GRP-GENOWS	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
GRPHTROWS1	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
GRP-OWSSTK	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. SIP Violation = The source is able to comply with applicable PM and opacity regulations without the use of PM collection equipment and has not been found to be in violation of any visible emission standard in a State Implementation Plan. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
GRP-VTWF2	30 TAC Chapter 115, Vent Gas Controls	R5121-1	Chapter 115 Division = The vent stream does not originate from a source for which another Division in 30 TAC Chapter 115 establishes a control requirement, emission specification, or exemption for that source. Combustion Exhaust = The vent stream is not from a combustion unit exhaust or the combustion unit is used as a control device for a vent stream originating from a noncombustion source subject to 30 TAC Chapter 115, Subchapter B, Division 2. Vent Type = Vent gas stream emissions of the specified classes of VOCs including aldehydes, alcohols, aromatics, ethers, olefins, peroxides, amines, acids, esters, ketones, sulfides, and branched chain hydrocarbons (C8 and above). Combined 24-Hour VOC Weight = Combined VOC weight is less than or equal to 100 pounds (45.4 kg). VOC Concentration/Emission Rate @ Max Operating Conditions = The VOC concentration or emission rate is less than the applicable exemption limit at maximum actual operating conditions and the alternate recordkeeping requirements of 30 TAC § 115.126(4) are being selected.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
PUMPFW-OWS	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
U-5	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
U-6	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
GRP-PWASH1	30 TAC Chapter 115, Degreasing Processes	R5412-1	Solvent Degreasing Machine Type = Cold solvent cleaning machine. Alternate Control Requirement = The TCEQ Executive Director has not approved an alternative control requirement as allowed under 30 TAC § 115.413 or not alternative has been requested. Solvent Sprayed = A solvent is sprayed. Solvent Vapor Pressure = Solvent vapor pressure is less than or equal to 0.6 psia as measured at 100 degrees Fahrenheit. Solvent Heated = The solvent is not heated to a temperature greater than 120° F. Parts Larger than Drainage = Cleaned parts for which the machine is authorized to clean are larger than the internal drainage facility of the machine. Drainage Area = Area is greater than or equal to 16 square inches. Disposal in Enclosed Containers = Waste solvent is properly disposed of in enclosed containers.	

* - The “unit attributes” or operating conditions that determine what requirements apply
** - Notes changes made to the automated results from the DSS, and a brief explanation why

NSR Versus Title V FOP

The state of Texas has two Air permitting programs, New Source Review (NSR) and Title V Federal Operating Permits. The two programs are substantially different both in intent and permit content.

NSR is a preconstruction permitting program authorized by the Texas Clean Air Act and Title I of the Federal Clean Air Act (FCAA). The processing of these permits is governed by 30 Texas Administrative Code (TAC) Chapter 116.111. The Title V Federal Operating Program is a federal program authorized under Title V of the FCAA that has been delegated to the state of Texas to administer and is governed by 30 TAC Chapter 122. The major differences between the two permitting programs are listed in the table below:

NSR Permit	Federal Operating Permit(FOP)
Issued Prior to new Construction or modification of an existing facility	For initial permit with application shield, can be issued after operation commences; significant revisions require approval prior to operation.
Authorizes air emissions	Codifies existing applicable requirements, does not authorize new emissions
Ensures issued permits are protective of the environment and human health by conducting a health effects review and that requirement for best available control technology (BACT) is implemented.	Applicable requirements listed in permit are used by the inspectors to ensure proper operation of the site as authorized. Ensures that adequate monitoring is in place to allow compliance determination with the FOP.
Up to two Public notices may be required. Opportunity for public comment and contested case hearings for some authorizations.	One public notice required. Opportunity for public comments. No contested case hearings.
Applies to all point source emissions in the state.	Applies to all major sources and some non-major sources identified by the EPA.
Applies to facilities: a portion of site or individual emission sources	One or multiple FOPs cover the entire site (consists of multiple facilities)
Permits include terms and conditions under which the applicant must construct and operate its various equipment and processes on a facility basis.	Permits include terms and conditions that specify the general operational requirements of the site; and also include codification of all applicable requirements for emission units at the site.
Opportunity for EPA review for Federal Prevention of Significant Deterioration (PSD) and Nonattainment (NA) permits for major sources.	Opportunity for EPA review, Affected states review, and a Public petition period for every FOP.
Permits have a table listing maximum emission limits for pollutants	Permit has an applicable requirements table and Periodic Monitoring (PM) / Compliance Assurance Monitoring (CAM) tables which document applicable monitoring requirements.
Permits can be altered or amended upon application by company. Permits must be issued before construction or modification of facilities can begin.	Permits can be revised through several revision processes, which provide for different levels of public notice and opportunity to comment. Changes that would be significant revisions require that a revised permit be issued before those changes can be operated.
NSR permits are issued independent of FOP requirements.	FOP are independent of NSR permits, but contain a list of all NSR permits incorporated by reference

New Source Review Requirements

Below is a list of the New Source Review (NSR) permits for the permitted area. These NSR permits are incorporated by reference into the operating permit and are enforceable under it. These permits can be found in the main TCEQ file room,

located on the first floor of Building E, 12100 Park 35 Circle, Austin, Texas. The Public Education Program may be contacted at 1-800-687-4040 or the Air Permits Division (APD) may be contacted at 1-512-239-1250 for help with any question.

Additionally, the site contains emission units that are permitted by rule under the requirements of 30 TAC Chapter 106, Permits by Rule. The following table specifies the permits by rule that apply to the site. All current permits by rule are contained in Chapter 106. Outdated 30 TAC Chapter 106 permits by rule may be viewed at the following Web site:

www.tceq.texas.gov/permitting/air/permitbyrule/historical_rules/old106list/index106.html

Outdated Standard Exemption lists may be viewed at the following Web site:

www.tceq.texas.gov/permitting/air/permitbyrule/historical_rules/oldselist/se_index.html

The status of air permits and applications and a link to the Air Permits Remote Document Server is located at the following Web site:

www.tceq.texas.gov/permitting/air/nav/air_status_permits.html

New Source Review Authorization References

Prevention of Significant Deterioration (PSD) Permits	
PSD Permit No.: PSDTX1037	Issuance Date: 08/31/2015
PSD Permit No.: PSDTX742M1	Issuance Date: 04/10/2012
Title 30 TAC Chapter 116 Permits, Special Permits, and Other Authorizations (Other Than Permits By Rule, PSD Permits, or NA Permits) for the Application Area.	
Authorization No.: 101006	Issuance Date: 03/29/2012
Authorization No.: 111116	Issuance Date: 07/29/2013
Authorization No.: 136922	Issuance Date: 12/22/2015
Authorization No.: 137903	Issuance Date: 01/21/2016
Authorization No.: 1491	Issuance Date: 03/06/2014
Authorization No.: 1492	Issuance Date: 03/17/2014
Authorization No.: 1652	Issuance Date: 08/07/2009
Authorization No.: 18426	Issuance Date: 04/10/2012
Authorization No.: 45640	Issuance Date: 03/06/2012
Authorization No.: 51186	Issuance Date: 02/08/2012
Authorization No.: 52616	Issuance Date: 04/10/2012
Authorization No.: 52617	Issuance Date: 05/16/2012
Authorization No.: 70492	Issuance Date: 08/31/2015
Authorization No.: 73932	Issuance Date: 04/24/2014
Authorization No.: 73935	Issuance Date: 04/24/2014
Authorization No.: 90267	Issuance Date: 09/17/2009
Authorization No.: 99915	Issuance Date: 12/07/2011
Authorization No.: PAL11	Issuance Date: 06/13/2007

New Source Review Authorization References

Permits By Rule (30 TAC Chapter 106) for the Application Area	
Number: 106.102	Version No./Date: 09/04/2000
Number: 106.122	Version No./Date: 09/04/2000
Number: 106.181	Version No./Date: 11/01/2001
Number: 106.227	Version No./Date: 09/04/2000
Number: 106.242	Version No./Date: 09/04/2000
Number: 106.244	Version No./Date: 09/04/2000
Number: 106.261	Version No./Date: 09/04/2000
Number: 106.261	Version No./Date: 11/01/2001
Number: 106.261	Version No./Date: 11/01/2003
Number: 106.262	Version No./Date: 09/04/2000
Number: 106.263	Version No./Date: 11/01/2001
Number: 106.265	Version No./Date: 09/04/2000
Number: 106.316	Version No./Date: 09/04/2000
Number: 106.317	Version No./Date: 09/04/2000
Number: 106.355	Version No./Date: 11/01/2001
Number: 106.371	Version No./Date: 03/14/1997
Number: 106.371	Version No./Date: 09/04/2000
Number: 106.373	Version No./Date: 09/04/2000
Number: 106.412	Version No./Date: 09/04/2000
Number: 106.454	Version No./Date: 11/01/2001
Number: 106.471	Version No./Date: 09/04/2000
Number: 106.472	Version No./Date: 03/14/1997
Number: 106.472	Version No./Date: 09/04/2000
Number: 106.473	Version No./Date: 09/04/2000
Number: 106.474	Version No./Date: 09/04/2000
Number: 106.475	Version No./Date: 09/04/2000
Number: 106.511	Version No./Date: 09/04/2000
Number: 106.512	Version No./Date: 06/13/2001
Number: 106.531	Version No./Date: 09/04/2000
Number: 106.532	Version No./Date: 09/04/2000
Number: 106.533	Version No./Date: 06/30/2004
Number: 3	Version No./Date: 05/08/1972
Number: 3	Version No./Date: 11/05/1986
Number: 3	Version No./Date: 09/13/1993

New Source Review Authorization References

Number: 5	Version No./Date: 12/01/1972
Number: 5	Version No./Date: 07/20/1992
Number: 5	Version No./Date: 04/05/1995
Number: 7	Version No./Date: 07/20/1992
Number: 8	Version No./Date: 05/04/1994
Number: 14	Version No./Date: 09/13/1993
Number: 51	Version No./Date: 11/05/1986
Number: 51	Version No./Date: 07/20/1992
Number: 53	Version No./Date: 07/20/1992
Number: 53	Version No./Date: 09/13/1993
Number: 57	Version No./Date: 12/01/1972
Number: 57	Version No./Date: 09/17/1973
Number: 57	Version No./Date: 05/05/1976
Number: 58	Version No./Date: 05/08/1972
Number: 60	Version No./Date: 12/01/1972
Number: 61	Version No./Date: 11/05/1986
Number: 61	Version No./Date: 09/12/1989
Number: 61	Version No./Date: 07/20/1992
Number: 64	Version No./Date: 01/08/1980
Number: 69	Version No./Date: 05/05/1976
Number: 70	Version No./Date: 06/07/1996
Number: 75	Version No./Date: 09/13/1993
Number: 103	Version No./Date: 06/07/1996
Number: 106	Version No./Date: 08/30/1988
Number: 106	Version No./Date: 07/20/1992

Emission Units and Emission Points

In air permitting terminology, any source capable of generating emissions (for example, an engine or a sandblasting area) is called an Emission Unit. For purposes of Title V, emission units are specifically listed in the operating permit when they have applicable requirements other than New Source Review (NSR), or when they are listed in the permit shield table.

The actual physical location where the emissions enter the atmosphere (for example, an engine stack or a sand-blasting yard) is called an emission point. For New Source Review preconstruction permitting purposes, every emission unit has an associated emission point. Emission limits are listed in an NSR permit, associated with an emission point. This list of emission points and emission limits per pollutant is commonly referred to as the “Maximum Allowable Emission Rate Table”, or “MAERT” for short. Specifically, the MAERT lists the Emission Point Number (EPN) that identifies the emission point, followed immediately by the Source Name, identifying the emission unit that is the source of those emissions on this table.

Thus, by reference, an emission unit in a Title V operating permit is linked by reference number to an NSR authorization, and its related emission point.

Monitoring Sufficiency

Federal and state rules, 40 CFR § 70.6(a)(3)(i)(B) and 30 TAC § 122.142(c) respectively, require that each federal operating permit include additional monitoring for applicable requirements that lack periodic or instrumental monitoring (which may include recordkeeping that serves as monitoring) that yields reliable data from a relevant time period that are representative of the emission unit's compliance with the applicable emission limitation or standard. Furthermore, the federal operating permit must include compliance assurance monitoring (CAM) requirements for emission sources that meet the applicability criteria of 40 CFR Part 64 in accordance with 40 CFR § 70.6(a)(3)(i)(A) and 30 TAC § 122.604(b).

With the exception of any emission units listed in the Periodic Monitoring or CAM Summaries in the FOP, the TCEQ Executive Director has determined that the permit contains sufficient monitoring, testing, recordkeeping, and reporting requirements that assure compliance with the applicable requirements. If applicable, each emission unit that requires additional monitoring in the form of periodic monitoring or CAM is described in further detail under the Rationale for CAM/PM Methods Selected section following this paragraph.

Rationale for Compliance Assurance Monitoring (CAM)/ Periodic Monitoring Methods Selected

Compliance Assurance Monitoring (CAM):

Compliance Assurance Monitoring (CAM) is a federal monitoring program established under Title 40 Code of Federal Regulations Part 64 (40 CFR Part 64).

Emission units are subject to CAM requirements if they meet the following criteria:

1. the emission unit is subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement;

2. the emission unit uses a control device to achieve compliance with the emission limitation or standard specified in the applicable requirement; and

3. the emission unit has the pre-control device potential to emit greater than or equal to the amount in tons per year for a site to be classified as a major source.

The following table(s) identify the emission unit(s) that are subject to CAM:

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1153
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a 6-minute average except during periods defined in 111.111(a)(1)(E)	
Basis of CAM: The 20% opacity deviation limit is consistent with the 20% opacity limit specified in 40 CFR Part 60, Subpart D. Because the particulate mass emission limit specified in 40 CFR Part 60, Subpart D is more stringent than the mass limit specified in 30 TAC §111.153(b), demonstrating compliance with the 20% opacity limit also demonstrates compliance with the lb/MMBtu limit in 30 TAC § 111.153(b). The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: D1-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1153
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a 6-minute average except during periods defined in 111.111(a)(1)(E)	
Basis of CAM: The 20% opacity deviation limit is consistent with the 20% opacity limit specified in 40 CFR Part 60, Subpart D. Because the particulate mass emission limit specified in 40 CFR Part 60, Subpart D is more stringent than the mass limit specified in 30 TAC §111.153(b), demonstrating compliance with the 20% opacity limit also demonstrates compliance with the lb/MMBtu limit in 30 TAC § 111.153(b). The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: D2-BH	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 20% opacity over a six-minute average except for one six-minute period per hour of no more than 27% opacity	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: P-5 JKS1	
Control Device ID No.: FF1	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1153
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 10% opacity over a 6-minute average	
Basis of CAM: The 10% opacity deviation limit is consistent with NSR Permit 18426/PSDTX742M1, and is more stringent than the 20% opacity limit specified in 40 CFR Part 60, Subpart Da. Because the particulate mass emission limit specified in 40 CFR Part 60, Subpart Da is more stringent than the mass limit specified in 30 TAC §111.153(b), demonstrating compliance with the 10% opacity limit also demonstrates compliance with the lb/MMBtu limit in 30 TAC § 111.153(b). The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: P-5 JKS1	
Control Device ID No.: WS-1	Control Device Type: Wet Scrubber
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: R-112-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO_2 concentration	
Minimum Frequency: four times per hour	
Averaging Period: hourly	
Deviation Limit: Greater than 3.0 lb/MMBtu sulfur dioxide concentration average hourly	
Basis of CAM: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: P-6	
Control Device ID No.: FF1	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1153
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Greater than 10% opacity over a 6-minute average	
Basis of CAM: The 10% opacity deviation limit is consistent with NSR Permit 70492/PSDTX1037, and is more stringent than the 20% opacity limit specified in 40 CFR Part 60, Subpart Da. Because the particulate mass emission limit specified in 40 CFR Part 60, Subpart Da is more stringent than the mass limit specified in 30 TAC §111.153(b), demonstrating compliance with the 10% opacity limit also demonstrates compliance with the lb/MMBtu limit in 30 TAC § 111.153(b). The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: P-6	
Control Device ID No.: WS-1	Control Device Type: Wet Scrubber
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: R2009
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO_2 concentration	
Minimum Frequency: four times per hour	
Averaging Period: hourly	
Deviation Limit: Greater than 3.0 lb/MMBtu sulfur dioxide concentration averaged hourly	
Basis of CAM: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Periodic Monitoring:

The Federal Clean Air Act requires that each federal operating permit include monitoring sufficient to assure compliance with the terms and conditions of the permit. Most of the emission limits and standards applicable to emission units at Title V sources include adequate monitoring to show that the units meet the limits and standards. For those requirements that do not include monitoring, or where the monitoring is not sufficient to assure compliance, the federal operating permit must include such monitoring for the emission units affected. The following emission units are subject to periodic monitoring requirements because the emission units are subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement that does not already require monitoring, or the monitoring for the applicable requirement is not sufficient to assure compliance:

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: R-112-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO_2 concentration	
Minimum Frequency: four times per hour	
Averaging Period: three-hour period	
Deviation Limit: Greater than 3.0 lb/MMBtu sulfur dioxide averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO_2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: NO_X	Main Standard: § 60.44(a)(1)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than 0.2 lb/MMBtu nitrogen oxide concentration averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: NO_X	Main Standard: § 60.44(a)(3)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than 0.7 lb/MMBtu nitrogen oxide concentration averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: NO_X	Main Standard: § 60.44(a)(3)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than 0.7 lb/MMBtu nitrogen oxide concentration averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: BOILER 1 JTD1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: NO_X	Main Standard: § 60.44(b)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than the limit calculated using the equation listed in 60.44(b) averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: R-112-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO_2 concentration	
Minimum Frequency: four times per hour	
Averaging Period: three-hour period	
Deviation Limit: Greater than 3.0 lb/MMBtu sulfur dioxide averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO_2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: NO_X	Main Standard: § 60.44(a)(1)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than 0.2 lb/MMBtu nitrogen oxide concentration averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: NO_X	Main Standard: § 60.44(a)(3)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than 0.7 lb/MMBtu nitrogen oxide concentration averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: NO_X	Main Standard: § 60.44(a)(3)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than 0.7 lb/MMBtu nitrogen oxide concentration averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: BOILER 2 JTD2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: NO_X	Main Standard: § 60.44(b)
Monitoring Information	
Indicator: NO_X concentration	
Minimum Frequency: four times per hour	
Averaging Period: 3-hour period	
Deviation Limit: Greater than the limit calculated using the equation listed in 60.44(b) averaged over a 3-hour period	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NO_X CEMS/PEMS to measure NO_X concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NO_X concentration is provided as a monitoring option for any control device because an increase in NO_X concentration may be indicative of the control device performance. Outlet NO_X concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: ETH-UST	
Control Device ID No.: FP-1	Control Device Type: Other Control Device Type
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Storage of VOCs	SOP Index No.: R115-1
Pollutant: VOC	Main Standard: § 115.112(c)(1)
Monitoring Information	
Indicator: Structural Integrity of the Pipe	
Minimum Frequency: Emptied and degassed	
Averaging Period: n/a	
Deviation Limit: Failure to inspect fill pipe or conduct any necessary repairs before tank is refilled	
Basis of monitoring: The periodic monitoring option provided for emission units using a submerged fill pipe is location of the submerged fill pipe and structural integrity of the pipe. The location and the integrity of the pipe ensure that loading operations are controlled to prevent splash fill and reduce generated vapors; therefore, less emissions are released to the atmosphere. This approach was included as an option by the EPA in the “Periodic Monitoring Technical Reference Document” (April 1999) to monitor VOC sources.	

Unit/Group/Process Information	
ID No.: ETH-UST	
Control Device ID No.: FP-1	Control Device Type: Other Control Device Type
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Storage of VOCs	SOP Index No.: R115-1
Pollutant: VOC	Main Standard: § 115.112(c)(1)
Monitoring Information	
Indicator: Liquid Level	
Minimum Frequency: Once per day	
Averaging Period: n/a	
Deviation Limit: Liquid level fall below the fill pipe level	
Basis of monitoring: The periodic monitoring option provided for emission units using a submerged fill pipe is location of the submerged fill pipe and structural integrity of the pipe. The location and the integrity of the pipe ensure that loading operations are controlled to prevent splash fill and reduce generated vapors; therefore, less emissions are released to the atmosphere. This approach was included as an option by the EPA in the “Periodic Monitoring Technical Reference Document” (April 1999) to monitor VOC sources.	

Unit/Group/Process Information	
ID No.: G-1A	
Control Device ID No.: FP-1	Control Device Type: Other Control Device Type
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Storage of VOCs	SOP Index No.: R-5112-1
Pollutant: VOC	Main Standard: § 115.112(c)(1)
Monitoring Information	
Indicator: Structural Integrity of the Pipe	
Minimum Frequency: Emptied and degassed	
Averaging Period: n/a	
Deviation Limit: Failure to inspect the structural integrity of the fill pipe and record each time the storage vessel is emptied and degassed shall be reported as a deviation.	
Basis of monitoring: The periodic monitoring option provided for emission units using a submerged fill pipe is location of the submerged fill pipe and structural integrity of the pipe. The location and the integrity of the pipe ensure that loading operations are controlled to prevent splash fill and reduce generated vapors; therefore, less emissions are released to the atmosphere. This approach was included as an option by the EPA in the “Periodic Monitoring Technical Reference Document” (April 1999) to monitor VOC sources.	

Unit/Group/Process Information	
ID No.: G-1A	
Control Device ID No.: FP-1	Control Device Type: Other Control Device Type
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Storage of VOCs	SOP Index No.: R-5112-1
Pollutant: VOC	Main Standard: § 115.112(c)(1)
Monitoring Information	
Indicator: Record of Tank Construction Specifications	
Minimum Frequency: n/a	
Averaging Period: n/a	
Deviation Limit: Failure to maintain a record of the tank construction specifications will be reported as a deviation.	
Basis of monitoring: The periodic monitoring option provided for emission units using a submerged fill pipe is location of the submerged fill pipe and structural integrity of the pipe. The location and the integrity of the pipe ensure that loading operations are controlled to prevent splash fill and reduce generated vapors; therefore, less emissions are released to the atmosphere. This approach was included as an option by the EPA in the “Periodic Monitoring Technical Reference Document” (April 1999) to monitor VOC sources.	

Unit/Group/Process Information	
ID No.: GRP-COAL1	
Control Device ID No.: DC-1	Control Device Type: Fabric Filter
Control Device ID No.: DC-101	Control Device Type: Fabric Filter
Control Device ID No.: DC-14	Control Device Type: Fabric Filter
Control Device ID No.: DC-2	Control Device Type: Fabric Filter
Control Device ID No.: DC-201	Control Device Type: Fabric Filter
Control Device ID No.: DC-3	Control Device Type: Fabric Filter
Control Device ID No.: DC-4A/4B	Control Device Type: Fabric Filter
Control Device ID No.: DC-5	Control Device Type: Fabric Filter
Control Device ID No.: DC-6	Control Device Type: Fabric Filter
Control Device ID No.: DC-7	Control Device Type: Fabric Filter
Control Device ID No.: DC-8	Control Device Type: Fabric Filter
Control Device ID No.: DC-CCG016	Control Device Type: Fabric Filter
Control Device ID No.: PX-C01A/B	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Y	SOP Index No.: 60Y-1
Pollutant: PM (OPACITY)	Main Standard: § 60.254(a)
Monitoring Information	
Indicator: Pressure drop/opacity	
Minimum Frequency: Weekly	
Averaging Period: 6 minutes	
Deviation Limit: 1 inch water minimum, 6 inches water maximum AND maximum opacity of 20%	
Basis of monitoring: It is widely practiced and accepted to control particulate emissions by use of a fabric filter. The option to measure pressure drop is indicative of control device performance since a drop in pressure may indicate holes or tears in the filter or increased pressure may indicate the blinding of bags or the filter has not been adequately cleaned. The deviation limit is based on the most recent performance test, the manufacturer's recommendations, engineering calculations, and/or historical data. The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-COAL2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Y	SOP Index No.: 60Y-1
Pollutant: PM (Opacity)	Main Standard: § 60.254(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: once per month	
Averaging Period: Six-minutes	
Deviation Limit: Maximum opacity of 20%	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-GENOWS	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(A)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: Maximum opacity of 30%; except during periods defined in 30 TAC 111.111(a)(1)(E)	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRPHTROWS1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(A)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: Maximum opacity of 30%; except during periods defined in 30 TAC 111.111(a)(1)(E)	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-LIME2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart OOO	SOP Index No.: 60OOO-1
Pollutant: PM (OPACITY)	Main Standard: § 60.672(b)-Table 3
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: once per month	
Averaging Period: Six-minutes	
Deviation Limit: Maximum opacity of 10%	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-LIME2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart OOO	SOP Index No.: 60OOO-1
Pollutant: PM (OPACITY)	Main Standard: § 60.672(f)-Table 2
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: once per month	
Averaging Period: Six-minutes	
Deviation Limit: Maximum opacity of 7%	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-OWSSTK	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel type/opacity	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Firing an alternate fuel for greater than 24 consecutive hours without conducting a visible emissions observation and a Test Method 9 is not performed; opacity greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-OWSSTM	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1153
Pollutant: PM	Main Standard: § 111.153(c)
Monitoring Information	
Indicator: Fuel type/Fuel firing rate	
Minimum Frequency: Annually or at any time an alternate fuel is fired	
Averaging Period: 1 hr	
Deviation Limit: Firing an alternate fuel at a rate greater than 148.6 kgal/hr	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel, the permit holder may establish a maximum fuel consumption rate using applicable AP-42 emission factors for particulate matter. It is widely practiced and accepted to use performance tests, manufacturer's recommendations, engineering calculations and/or historical data to establish a correlation between fuel consumption and emission rates. In situations where such a correlation exists, measuring, calculating and recording the fuel consumption rate indicates whether the emission limitation or standard is being met.	

Unit/Group/Process Information	
ID No.: GRP-OWSSTM	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: R-112-1
Pollutant: SO_2	Main Standard: § 112.9(a)
Monitoring Information	
Indicator: Sulfur content of liquid fuel	
Minimum Frequency: quarterly when burning fuel oil and within 24 hours of a change from primary fuel	
Averaging Period: n/a	
Deviation Limit: Burning fuel oil greater than 0.7% sulfur	
Basis of monitoring: A common way to determine SO2 emissions is by determining the amount (percentage) of sulfur in fuel combusted by an emission unit. This quantity along with stack flow rate and quantity of fuel combusted may be used to calculate the amount of SO2 emitted to the atmosphere.	

Unit/Group/Process Information	
ID No.: GRP-PWASH1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Degreasing Processes	SOP Index No.: R5412-1
Pollutant: VOC	Main Standard: § 115.412(1)
Monitoring Information	
Indicator: Visual Inspection	
Minimum Frequency: Monthly	
Averaging Period: n/a	
Deviation Limit: Any monitoring data indicating non-compliance with 30 TAC § 115.412(1)(A), (1)(C), (1)(D), (1)(F) shall be considered and reported as a deviation.	
Basis of monitoring: The monitoring option to cover cold cleaner or the open-top vapor cleaner was included in the EPA “Periodic Monitoring Technical Reference Document” (April 1999) to monitor VOC sources. In addition to covering the cleaner records of monthly inspections of equipment is an effective way to ensure that the system is operating in accordance with its design.	

Unit/Group/Process Information	
ID No.: LFUG-CRSH	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart OOO	SOP Index No.: 60OOO-1
Pollutant: PM (OPACITY)	Main Standard: § 60.672(e)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: once per month	
Averaging Period: Six-minutes	
Deviation Limit: Maximum opacity of 7%	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: PUMPFW-OWS	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(A)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: Maximum opacity of 30%; except during periods defined in 30 TAC 111.111(a)(1)(E)	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Compliance Review

1. In accordance with 30 TAC Chapter 60, the compliance history was reviewed on July 17, 2017.
   Site rating: 0.89 / Satisfactory Company rating: 0.49 / Satisfactory
   (High < 0.10; Satisfactory ≥ 0.10 and ≤ 55; Unsatisfactory > 55)
2. Has the permit changed on the basis of the compliance history or site/company rating? ..... No

Permit reviewer notes: The Compliance History ratings are effective as of 09/01/2014, since the compliance period is defined in 30 TAC §60.1(b) as the 5 year period preceding the application received date. This renewal application was received on 07/15/2015.

Site/Permit Area Compliance Status Review

1. Were there any out-of-compliance units listed on Form OP-ACPS? ..... No
2. Is a compliance plan and schedule included in the permit? ..... No

Available Unit Attribute Forms

OP-UA1 - Miscellaneous and Generic Unit Attributes
OP-UA2 - Stationary Reciprocating Internal Combustion Engine Attributes
OP-UA3 - Storage Tank/Vessel Attributes
OP-UA4 - Loading/Unloading Operations Attributes
OP-UA5 - Process Heater/Furnace Attributes
OP-UA6 - Boiler/Steam Generator/Steam Generating Unit Attributes
OP-UA7 - Flare Attributes
OP-UA8 - Coal Preparation Plant Attributes
OP-UA9 - Nonmetallic Mineral Process Plant Attributes
OP-UA10 - Gas Sweetening/Sulfur Recovery Unit Attributes
OP-UA11 - Stationary Turbine Attributes
OP-UA12 - Fugitive Emission Unit Attributes
OP-UA13 - Industrial Process Cooling Tower Attributes
OP-UA14 - Water Separator Attributes
OP-UA15 - Emission Point/Stationary Vent/Distillation Operation/Process Vent Attributes
OP-UA16 - Solvent Degreasing Machine Attributes
OP-UA17 - Distillation Unit Attributes
OP-UA18 - Surface Coating Operations Attributes
OP-UA19 - Wastewater Unit Attributes
OP-UA20 - Asphalt Operations Attributes
OP-UA21 - Grain Elevator Attributes
OP-UA22 - Printing Attributes
OP-UA24 - Wool Fiberglass Insulation Manufacturing Plant Attributes
OP-UA25 - Synthetic Fiber Production Attributes
OP-UA26 - Electroplating and Anodizing Unit Attributes
OP-UA27 - Nitric Acid Manufacturing Attributes
OP-UA28 - Polymer Manufacturing Attributes
OP-UA29 - Glass Manufacturing Unit Attributes
OP-UA30 - Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mill Attributes
OP-UA31 - Lead Smelting Attributes
OP-UA32 - Copper and Zinc Smelting/Brass and Bronze Production Attributes
OP-UA33 - Metallic Mineral Processing Plant Attributes
OP-UA34 - Pharmaceutical Manufacturing
OP-UA35 - Incinerator Attributes
OP-UA36 - Steel Plant Unit Attributes
OP-UA37 - Basic Oxygen Process Furnace Unit Attributes
OP-UA38 - Lead-Acid Battery Manufacturing Plant Attributes
OP-UA39 - Sterilization Source Attributes
OP-UA40 - Ferroalloy Production Facility Attributes
OP-UA41 - Dry Cleaning Facility Attributes

OP-UA42 - Phosphate Fertilizer Manufacturing Attributes
OP-UA43 - Sulfuric Acid Production Attributes
OP-UA44 - Municipal Solid Waste Landfill/Waste Disposal Site Attributes
OP-UA45 - Surface Impoundment Attributes
OP-UA46 - Epoxy Resins and Non-Nylon Polyamides Production Attributes
OP-UA47 - Ship Building and Ship Repair Unit Attributes
OP-UA48 - Air Oxidation Unit Process Attributes
OP-UA49 - Vacuum-Producing System Attributes
OP-UA50 - Fluid Catalytic Cracking Unit Catalyst Regenerator/Fuel Gas Combustion Device/Claus Sulfur Recovery Plant Attributes
OP-UA51 - Dryer/Kiln/Oven Attributes
OP-UA52 - Closed Vent Systems and Control Devices
OP-UA53 - Beryllium Processing Attributes
OP-UA54 - Mercury Chlor-Alkali Cell Attributes
OP-UA55 - Transfer System Attributes
OP-UA56 - Vinyl Chloride Process Attributes
OP-UA57 - Cleaning/Depainting Operation Attributes
OP-UA58 - Treatment Process Attributes
OP-UA59 - Coke By-Product Recovery Plant Attributes
OP-UA60 - Chemical Manufacturing Process Unit Attributes
OP-UA61 - Pulp, Paper, or Paperboard Producing Process Attributes
OP-UA62 - Glycol Dehydration Unit Attributes
OP-UA63 - Vegetable Oil Production Attributes